4. Trends in Natural Gas Transportation Rates

This chapter discusses trends in natural gas transportation rates for the period 1988 through 1994 and how Federal regulations and policies affect those trends.[55] Regulatory reform, new legislation, and restructuring in the natural gas industry have expanded options for sellers and buyers of natural gas, resulting in increased competition within the industry. Buyers now have more choices for purchasing gas, and ancillary services such as pipeline transmission and storage rights. Suppliers have a wider range of prospective customers and greater flexibility in setting the terms of sale. This competition has contributed to higher gas throughput on the interstate pipeline system and lower average transmission prices (Figure 9).[56] From 1988 through 1994, deliveries to end users increased 16 percent, while average transmission markups declined 16 percent, from $1.49 to $1.25 per thousand cubic feet. In the face of increasing competition, many segments of the industry have become more efficient and reduced costs, to the general benefit of consumers.

Natural gas consumers have benefited in two ways. First, the wellhead price of natural gas, effectively the price of the commodity itself, has declined substantially. Between 1988 and 1994, the average wellhead price of natural gas, in real terms, fell 11 percent, from $2.05 to $1.83 per thousand cubic feet. Average prices paid by some customer classes, specifically onsystem industrial and electric utility customers, have declined even more than the decline in the wellhead price, indicating that additional benefits have been obtained from lower costs of transmission and other delivery services. Residential and commercial customers, who for the most part obtain all of their service from local distribution companies, have not experienced significant reductions in the costs of service beyond the decrease in wellhead prices. Although these customers have paid less for transmission, distribution costs have increased resulting in little overall change.

In total, EIA estimates that consumers paid almost $6.5 billion (9 percent) less, in real terms, for natural gas service (including wellhead purchases combined with transmission and distribution charges) in 1994 than they would have in 1988. This estimate includes $2.5 billion in reduced transmission and distribution charges and $4 billion of savings resulting from the 11-percent reduction in wellhead prices since 1988. The bulk of the $2.5 billion represents the reduction in the fixed costs of transmission and distribution that do not vary with the volumes delivered. Because of data limitations, the estimate of total savings may be low because for offsystem industrial customers only the savings in wellhead prices are included. However, of the $6.5 billion savings, industrial customers were the main beneficiaries, receiving over half of the savings ($3.8 billion), while electric utilities and commercial customers each saw savings of $1.4 billion.

Another way to estimate savings is to compare the average price per thousand cubic feet to each end-use sector in 1994 and 1988. This method assumes that transmission and distribution costs would vary with the volumes delivered. In 1994, the price of 1 thousand cubic feet of gas (wellhead price plus delivery charges) to the end-use sectors was between 3 and 19 percent less than 1988 levels. The differential in savings stems from the range of prices different customer groups pay for natural gas deliveries. The prices are based on a number of elements, particularly the level and quality of service required.

The analysis in this chapter focuses only on the costs associated with the delivery of natural gas from the wellhead to the end user. Interstate pipeline companies transport gas from the supply areas to serve some customers directly, but much of the gas they transport is to the "citygate" of a local distribution company (LDC). LDC's then provide the distribution and other services needed to supply homeowners, commercial establishments, and other customers. The interstate pipeline companies are regulated at the Federal level, and the extensive regulatory changes caused by Orders 436 and 636 have directly affected the rates they charge. LDC's are regulated at the State level, and while some changes are being made at the State level comparable to the Federal level, there have not been extensive changes to date.

As discussed in Chapter 1, there are no publicly available data series on the actual prices paid by shippers on interstate pipeline companies. The information available relates only to the tariff rates (maximum rates) authorized by the Federal Energy Regulatory Commission (FERC). The analysis of transportation rates in this chapter uses several approaches, both qualitative and quantitative, to illustrate how transmission costs have been affected by legislative and regulatory changes. Sections of the chapter address:

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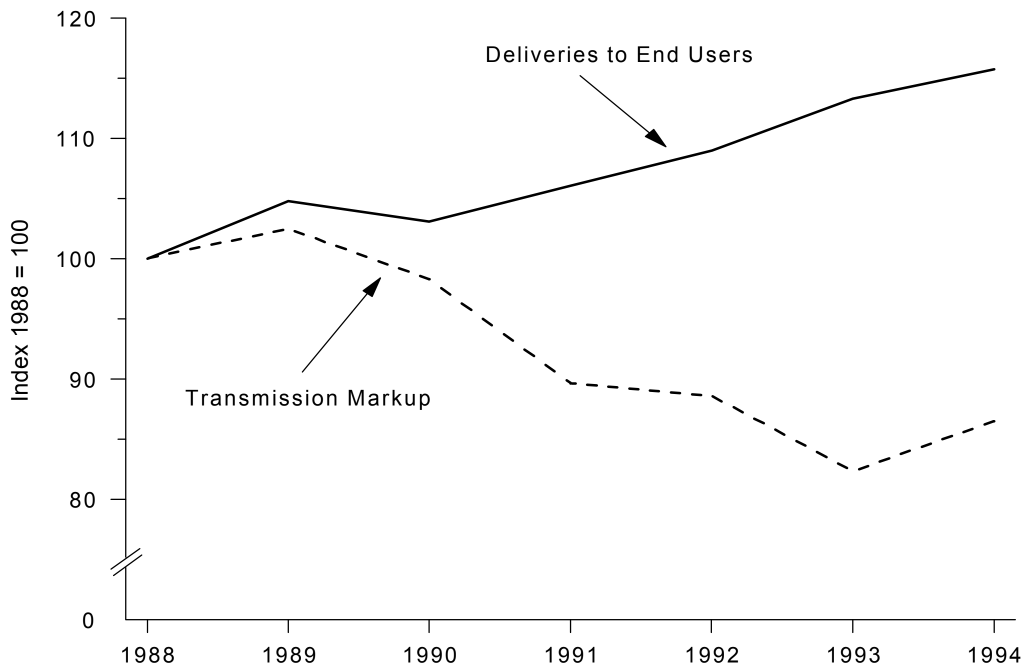
[55] All rates and prices are quoted in terms of real 1994 dollars.

[56] The transmission markup is calculated as the difference between the average citygate price and the average wellhead price. The transmission price (or markup) represents the average price paid for all services required to move gas from the wellhead to the local distributor. The data reflect the prices paid for gas sales services provided by LDC's only.

Figure 9. Indices of Natural Gas Transmission Markups and Deliveries to End Users, 1988-1994



Sources: Energy Information Administration, Office of Oil and Gas, derived from: 1988: Historical Monthly Energy Review 1973-1992 (August 1994). 1989-1994: Natural Gas Monthly (August 1995).

- Factors affecting interstate transportation rates. To understand how changes in laws and regulations can affect transportation rates, it is useful to look first at how rates are structured. This section first describes some of the key determinants used to develop interstate transmission rates and how economic and regulatory changes between 1988 and 1994 have affected the calculation of the rates. In addition, as the restructuring of the industry proceeded over the period addressed by this study, FERC implemented mechanisms for companies to recover costs associated with the restructuring, such as reformation of contracts, stranded investments, and other transition costs. Finally, the effect of the more competitive environment on rates charged by pipeline companies is briefly addressed.

- Trends in maximum rates for selected interstate corridors (Corridor Rate Analysis). Some indication of the overall movement in transportation rates over time can be obtained from looking at changes in the maximum rates charged by pipeline companies. This section looks at rates for 16 pipeline companies along 14 corridors. However, because pipeline companies often discount rates, the rates actually paid by many customers may be substantially less than the maximum rate approved by FERC.

- Impact of revenue from pipeline capacity release in offsetting payments for capacity reservation. Shippers holding capacity rights on interstate pipelines may release that capacity in the secondary capacity market if they do not need it. Revenues obtained from that capacity release are not reflected in the overall maximum rates discussed earlier, even though they lower the overall cost of shipping gas.

- Changes in transmission markups at the national and regional levels. A more aggregate measure of trends in transmission markups can be obtained by comparing the differences between wellhead, citygate, and end-use prices. Because of the options available to customers to use alternative transmission routes, analyzing rates along specific corridors may miss the impact of the increased flexibility available to customers. This section examines markups from the wellhead to the local distribution company and from the citygate to the end user, at both the national and regional levels.

Factors Affecting Interstate Pipeline Transportation Rates

Pipeline company tariff rates for interstate transportation services are determined using the traditional cost of service approach. The maximum (tariff) rate that a pipeline company can charge a particular customer is determined by several factors. The key determinants are: the rate base, the allowed rate of return on the rate base, the level of operating costs, the amount of capacity reserved, the load factor, the expected level of interruptible throughput, and the rate design (see Appendix D for additional information on the determinants of rates). This section discusses the impact of each of these determinants in isolation, that is, assuming all other factors remain constant. A quantitative assessment of the trend in each factor is also presented.

- Rate base. The rate base is the historical cost of physical capital on which the pipeline is entitled to earn a return. The rate base is generally calculated as net plant in service (gross gas plant in service plus construction work in progress less the accumulated depreciation, depletion and amortization) plus prepayments and inventory less accumulated deferred income taxes. Depreciation of the physical assets in service and abandonment or sales of existing plant lowers the rate base over time and will lower the maximum rate that pipeline companies are allowed to charge. However, this effect is offset by any investment in new capacity or the refurbishment of existing capacity which increases the rate base, and the maximum allowable rates.

  The 1988 through 1994 period was marked by a significant amount of new pipeline construction. As a result, the costs of new construction more than offset the effect of depreciation for the industry-wide rate base reflecting the physical capital used in providing transmission services. This new construction was undertaken for a variety of reasons, including hooking up new sources of supplies (both domestic and imports) and meeting the requirements of a 13 percent increase in consumption. As a result of this investment, the total rate base for the major pipeline companies grew, in nominal dollars, from $20.2 billion in 1988 to $25.6 billion in 1994 (Table 7).[57] One would expect rates to have increased over this period because of the increase in the rate base.

- Approved rate of return. The allowed rate of return (or the cost of capital), approved by FERC for each pipeline company, is a weighted average of the firm's cost of debt and the rate of return on equity as determined by the regulatory process. FERC examines a number of elements in determining the rate of return for a particular pipeline company, including capital structure, risk conditions, and other factors. Modifications to a pipeline company's approved rate of return alter its total cost of service, which, in turn, can lead to changes in that company's maximum rates for transportation services. From 1988 through 1994, approved rates of return for pipeline companies decreased, partly because their marginal cost of debt declined, as reflected by generally lower interest rates. For example, the rate for AA utility bonds declined from 10.26 to 8.21 percent. During this period, the decrease in the average approved rate of return for pipeline companies was more modest than the reduction in interest rates. One possible explanation is the relatively higher interest costs paid by the pipeline companies as a result of their low bond ratings.[58] Specifically, the settlement rates of return were largely flat at about 11.5 percent during most of the period but did decline in 1994 to approximately 10.2 percent[59] (Figure 10).

- Operation and maintenance (O&M) expenses. These are the direct costs of operating and maintaining pipeline facilities necessary to keep the system operational. O&M costs are reviewed as part of a rate hearing and any increases approved by FERC can be expected to result in higher rates. Changes in these costs that were not anticipated at the time of the rate hearing are not addressed until the next hearing and therefore do not affect the approved rate in the interim. As a result of the increased competition under open access, pipeline companies appear to have become more efficient, as evidenced by reductions in operating costs and administrative and general expenses and increases in employee productivity (measured by natural gas deliveries per employee).[60] Between 1988

[57]Rate base trends, only, are stated in nominal dollars to conform to the ratemaking process of computing rates. However, the return on rate base is converted to constant dollars to agree with other discussions.

[58]For additional information, see Energy Information Administration (EIA) report, Natural Gas 1994: Issues and Trends, DOE/EIA-0560(94) (July 1994).

[59]It should be noted that the rates cited represent only those revised rates that FERC approved ("settlement cases") during the year and hence, do not necessarily represent the entire industry. The number of settlement cases during 1993 and 1994 was 12 and 13, respectively, considerably below the 16 to 18 cases per year between 1989 and 1992.

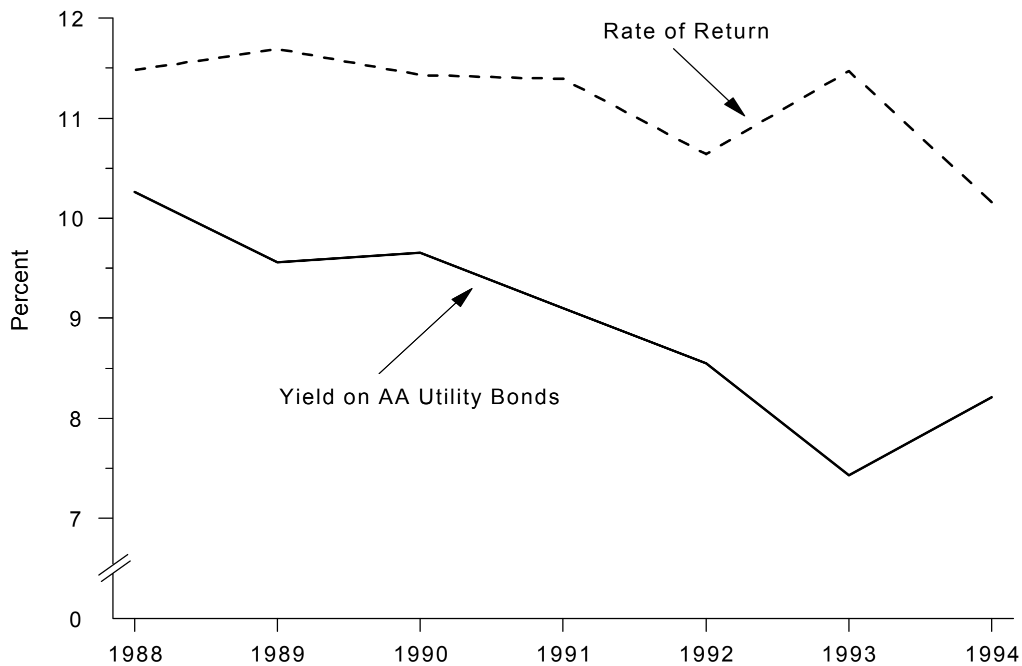
[60]For additional information, see the EIA report, "Natural Gas 1995: Issues and Trends," DOE/EIA-0560(95), to be published in the fall of 1995.

Table 7. Composite Rate Base, 1988-1994
(Billion Nominal Dollars)

Rate Base Elements	1988	1989	1990	1991	1992	1993	1994
Rate Base							
Gas Plant in Service	44.3	44.2	48.8	52.7	52.3	54.3	55.1
Accumulated Depreciation	26.1	26.5	28.1	30.5	28.6	29.7	29.7
Net Plant in Service	18.2	17.7	20.7	22.2	23.7	24.7	25.4
Additions to Rate Base	8.3	7.4	8.5	8.9	7.8	6.9	5.9
Subtractions from Rate Base	6.3	6.1	6.0	5.4	5.2	5.5	5.7
Total Rate Base	20.2	18.9	23.2	25.7	26.3	26.1	25.6

Note: Construction work in progress is included in additions to rate base.
Sources: 1988-1989: Energy Information Administration, Statistics of Interstate Natural Gas Pipeline Companies 1990 (April 1992). 1990-1994: Federal Energy Regulatory Commission (FERC) Form 2. "Annual Report of Major Natural Gas Companies," Balance Sheet File from FERC Gas Pipeline Data Bulletin Board System.

Figure 10. Average Yield on AA Utility Bonds and Rate of Return for Interstate Pipeline Companies, 1988-1994



Note: The rate of return represents the average settlement rate of return approved by the Federal Energy Regulatory Commission.
Sources: Yield on AA Utility Bonds: Moody's Investor Service, Inc., extracted from DRI History file: USQ0993.WS. Rate of Return: Federal Energy Regulatory Commission, Office of Pipeline Regulation.

and 1994, O&M costs declined in 1994 dollars from $8.5 billion to $5.4 billion (Table 8). In addition to efficiency improvements, falling O&M costs may be the result of several factors including technology improvements and the spin-off of pipeline facilities.

- Load profile. The load profile of a pipeline customer is indicated by its load factor, which is simply the ratio of its average (usually, the annual average) level of pipeline throughput to the maximum pipeline capacity it has reserved. Shippers with relatively large load factors are said to have higher load profiles, while relatively smaller load factors equate to lower load profiles. For example, local distribution companies that serve residential and commercial customers must reserve sufficient pipeline capacity to satisfy the wintertime peak demands for these customers, even though their off-season demand can be satisfied with substantially less capacity. Thus, an LDC's throughput averaged over the year is likely to be relatively low compared with the capacity it must reserve to meet peak demands. When this is the case, it is said to have a low load profile. The load profile affects the way in which fixed costs are assigned in computing rates. Pipeline customers with a low load factor will be charged higher average rates compared with customers with a high load factor. While this is an important consideration in determining rates, there is insufficient information regarding load profiles to provide a quantitative assessment of the impact of load factors on changes in transportation rates.

- Capacity reserved. An increase in the amount of capacity reserved on a pipeline tends to lower reservation rates because the fixed costs will be collected over more units of reserved capacity. Reservation charges are billed to a customer for each unit of capacity reserved, whether or not the capacity is used.[61] Data limitations do not permit a precise assessment of the trend in reserved capacity between 1988 and 1994. However, there is evidence to suggest that the amount of reserved capacity has increased. Much of the increase in deliveries to end users from 1988 through 1994 is accounted for by firm services (Figure 11).[62] While some of this increase in deliveries may be associated with higher utilization of existing reserved capacity, the overall average utilization of the pipeline system was about the same in 1991 and 1994 (see Chapter 3). The combination of increased firm deliveries and pipeline expansion during this period may indicate that the amount of reserved capacity has increased.

- Expected level of interruptible throughput. While interruptible rates may be lower than firm rates, interruptible throughput does contribute to fixed costs. When determining tariff rates, fixed costs are allocated between firm and interruptible services based on their respective loads on the pipeline.[63] The interruptible customers' load is estimated from their forecasted annual throughput level. As a result, an anticipated decrease in the level of interruptible throughput raises firm transportation rates by increasing the level of fixed costs allotted to firm transportation services. Interruptible throughput declined over the 1988 through 1994 period (Figure 11) putting upward pressure on firm transportation rates.

- Rate design. Firm customers pay a reservation charge to reserve pipeline capacity as well as a charge based on the amount of gas actually transported. Rate design refers to how fixed costs are allocated and collected in these two charges. From 1988 through 1991, the modified fixed-variable (MFV) rate design was widely used. Under this system, fixed costs were allocated to both the reservation and volumetric components of rates. FERC Order 636 stipulated the use of the straight fixed-variable (SFV) rate design. Under this method, all fixed costs are allocated to the reservation charge, while variable costs are allocated to a commodity or usage fee (Figure 12). This change in rate design tends to increase rates for low-load-factor customers and decrease rates for high-load-factor customers (see Chapter 2). The change to SFV reallocated approximately $1.7 billion from the usage fee to the reservation fee.[64]

- Take-or-pay costs. Contract reformation costs resulting from take-or-pay settlements associated with

[61] If a customer requires 1 million cubic feet (MMcf) of gas on a day during the month of January (assuming the pipeline company does not offer seasonal rates), that customer must reserve 1 MMcf of space on the pipeline for every day during the year.

[62] Besides traditional firm service, this includes released firm transportation, no-notice transportation, and short-term firm transportation. A pipeline company may sell the unused portion of any firm transportation capacity on its system on a short-term basis.

[63] The firm service load is derived from the amount of space firm service customers reserve on the pipeline or the measured load firm service imposes on the pipeline system during the period of maximum use.

[64] Monetary estimate from the Federal Energy Regulatory Commission, Order 636-A, footnote 314, 57 F.R. 36128,36173 (1992). Actual costs paid by any class of customers depend on the discounts from the maximum allowable rates that may be obtained from the pipeline company.

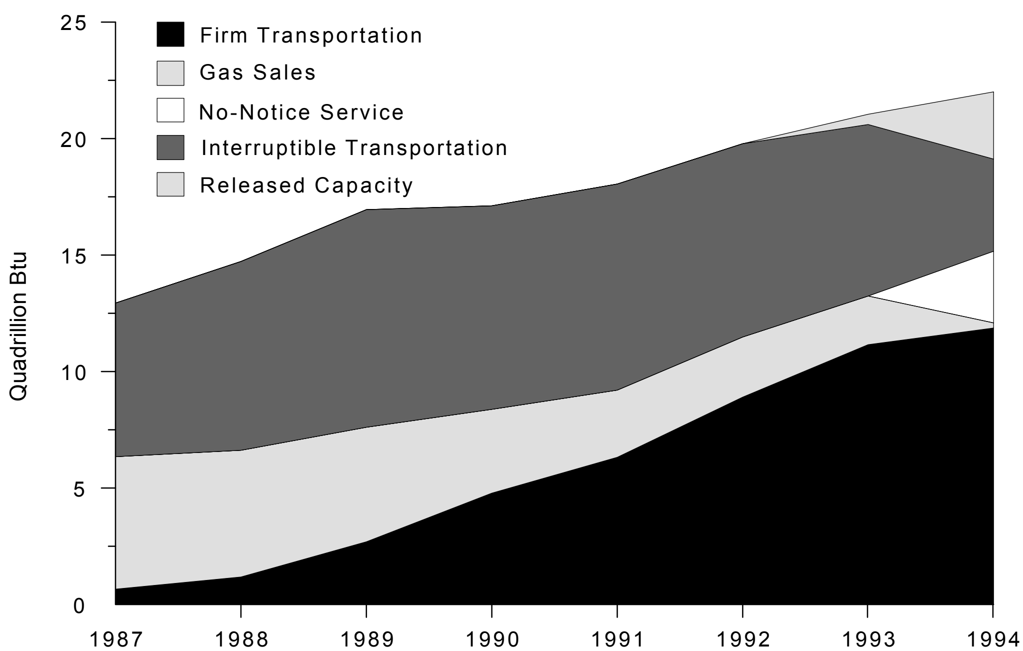
Table 8. Composite Cost of Service
(Billion 1994 Dollars)

Elements	1988	1989	1990	1991	1992	1993	1994
Return on Rate Base	2.8	2.6	2.9	3.1	2.9	3.1	2.6
Operation and Maintenance Expenses	8.5	9.3	6.1	9.0	7.5	6.9	5.4
Other Expenses	3.4	3.2	3.1	2.4	3.0	3.3	3.1
Total Cost of Service	14.6	15.1	12.2	14.6	13.4	13.3	11.1

Note: Return on Rate Base = Total Rate Base multiplied by FERC Approved Rate of Return.

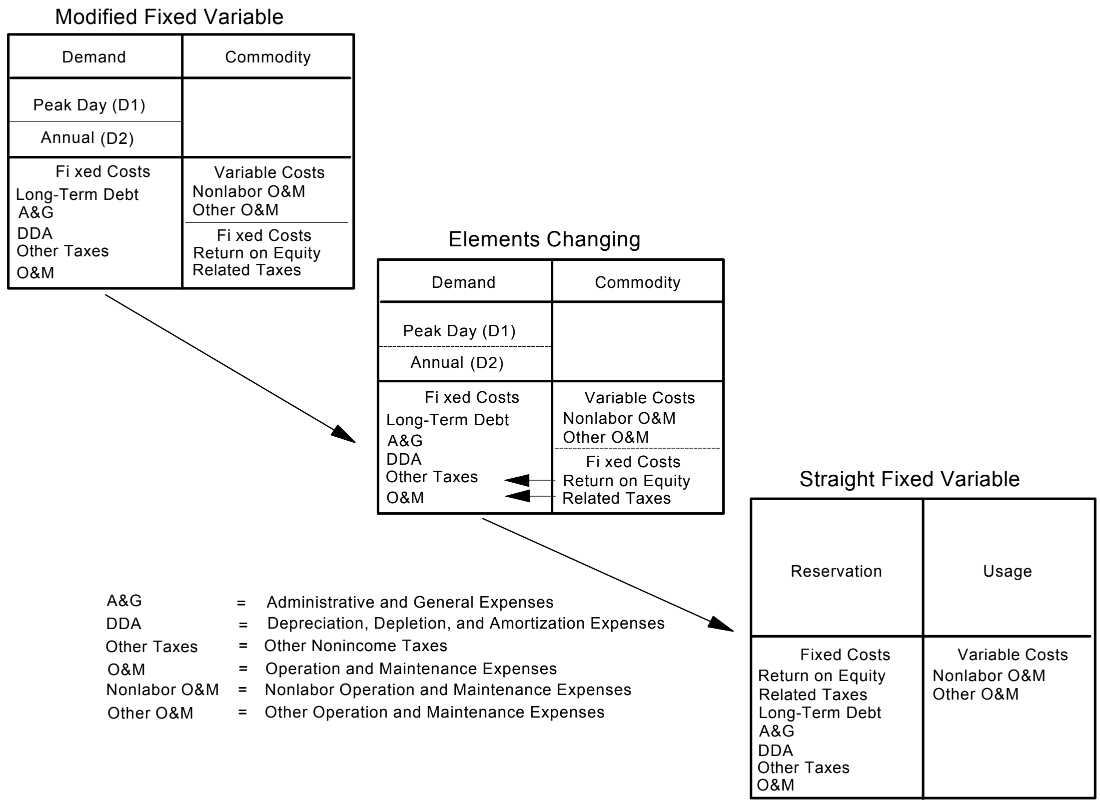
Sources: 1988-1989: Energy Information Administration, Statistics of Interstate Natural Gas Pipeline Companies 1990 (April 1992). 1990-1994: Federal Energy Regulatory Commission (FERC) Form 2. "Annual Report of Major Natural Gas Companies," Balance Sheet File from FERC Gas Pipeline Data Bulletin Board System.

Figure 11. Natural Gas Transmission by Type of Service, 1987-1994



Source: Interstate Natural Gas Association of America (INGAA), Gas Transportation Through 1994 (August 1995).

Figure 12. Rate Design in Transition: Modified to Straight Fixed Variable



Source: Energy Information Administration, Natural Gas 1992: Issues and Trends.

the implementation of Order 436 have totaled approximately $10.2 billion as of May 30, 1995.[65] Pipeline companies have agreed to absorb about $3.7 billion. Of the remaining $6.6 billion, $3.6 billion is being recovered through a surcharge on firm transportation customers and the remainder is being recovered through a surcharge on volumetric rates. Recovery of these take-or-pay costs began in the late 1980's and is expected to result in higher rates for some customers throughout the 1990's.

- Transition costs. As of August 1995, $2.7 billion in transition costs associated with Order 636 have been filed at FERC for recovery through increased transportation rates to shippers.[66] The $2.7 billion of costs include $1.4 billion of gas supply realignment costs; $0.6 billion of unrecovered gas costs; $0.7 billion of stranded costs, and $9 million for new facilities. Additional transition costs are likely and will probably affect rates for the next 3 to 5 years.

- Costs of pipeline expansion. For the period 1991 through 1994, the interstate pipeline companies spent $6.5 billion on expanding interstate pipeline capacity. Expansion costs generally have been passed through to all customers and will continue to influence transportation rates, because they are amortized over many years. Pipeline expansion costs increase the rate base and, subsequently, transportation rates.

Changes in the elements described above for determining rates offset and counterbalance each other. The rate design, which determines how costs are allocated and recovered from customer classes, probably has the most significant direct impact on rates. In addition, industry restructuring has resulted in significant costs associated with the changes implemented in the new regulations, including more than $10 billion in take-or-pay costs under Orders 436 and 500, and an additional $2.7 billion in transition costs associated with Order 636.

When Order 636 shifted the responsibility and risk of maintaining service from the interstate pipeline companies to the

[65] A contract provision obligating the buyer to pay for a certain minimum quantity of product, whether or not the buyer takes that quantity during the stated period.

[66] Shippers include any customer who uses transportation services.

local distribution companies and consumers, the allocation of costs for some services changed. For example, a charge that was previously included in the price paid for interstate transmission service may now be included in the distribution costs (or it may be paid directly by the end user and hence not reported by either the interstate pipeline or the local distribution company). This can affect the accounting (and reporting) of both the costs of long-haul transportation (by interstate pipeline companies) as well as local delivery charges (by local distribution companies). For this reason, only aggregate costs of transmission and distribution service are examined for some of the areas analyzed. In addition, firm transportation rates previously may have included a number of other services, such as storage and load-balancing. In this analysis, it was not possible to adjust the data to reflect a consistent definition over time. Therefore, trends in transportation rates may only be approximations.

The difficulty of differentiating distribution from transmission costs presents additional problems when analyzing the effects of Federal policies and regulations on transportation rates. Distribution rates charged by local distribution companies are regulated by State utility commissions not by FERC. Recently, some of the larger consuming States have been experimenting with various types of rate designs, such as market- and incentive-based rates, to introduce greater competitive forces into the distribution system. Some States are even advocating that LDC's unbundle their services.

Because of these and other data limitations, this analysis does not attempt separately to attribute specific changes in transportation rates to specific Federal legislation or regulations. Rather, the chapter presents general trends in transmission rates, showing how they are influenced in aggregate by regulations, legislation, and policies, as well as economic and market elements.

The Corridor Rate Analysis

A number of regulatory and market influences affected rates over the 1988 through 1994 period. One of the most significant regulatory changes that has had a direct impact on rates is FERC Order 636 and the resulting change in rate design to the straight fixed-variable (SFV) method. The analysis of transportation corridors examines the change in maximum transportation rates under Order 636 but does not isolate the changes in rates due exclusively to the SFV rate design. Rather, it assesses the net effect on transportation rates of all of the regulatory and market influences, including rate base changes, operating costs, taxes, depreciation, interest rates, capacity reserved, load profiles, rates of return, etc.

The analysis compares maximum firm transportation rates, including surcharges (tariff rates) charged before and after Order 636 went into effect. Although maximum rates may not apply to customers who pay discounted rates for services, pipeline company core customers generally pay maximum tariff rates. Therefore, the analysis of maximum rates will provide a basis on which to gauge the general movement of firm transportation rates. The tariff rates analyzed include surcharges such as Order 636 transition costs.

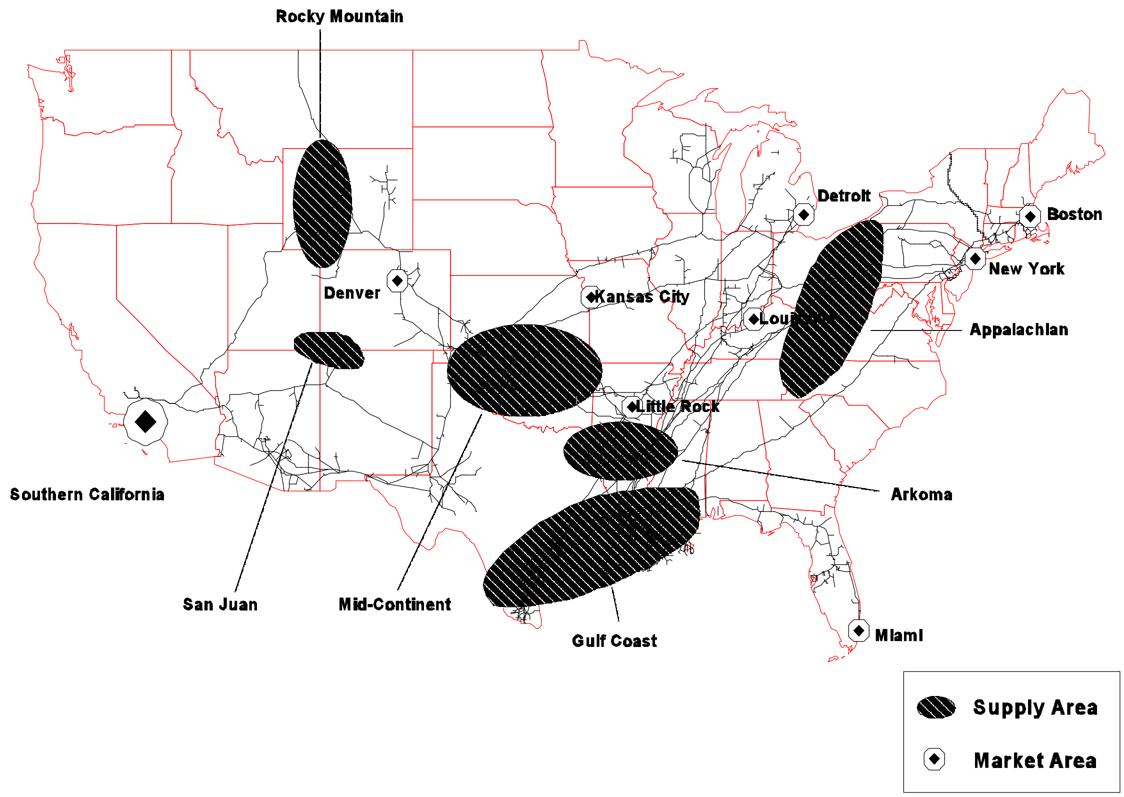
Firm transportation rates in 1994 were compared with rates in effect in 1991 for a sample of 14 supply/demand areas or corridors (Figure 13). The 16 companies represented in the sample have a combined service area that spans the country and a throughput level that is almost half the total industry throughput. The sample of corridors was developed based on the market corridors presented in the Foster Associates' December 1994 publication Competitive Profile of Natural Gas Services (discussed in more detail in Chapter 5).[67] For any single corridor in the sample, there may be several routes, with each route representing the transportation services of one or more pipeline companies. For instance, the corridor from the Gulf Coast supply area to the Boston market area includes two separate routes: (1) Texas Eastern Transmission Company and Algonquin Gas Transmission Corporation and (2) Tennessee Gas Pipeline Company. An aggregate or "unit" rate, representing the total transmission charge for moving 1 million Btu (MMBtu) of gas, was developed for each of the 21 routes in the sample. The results from the rate analysis are presented in constant 1994 dollars.

The analysis compares the unit cost for firm (i.e., noninterruptible) transportation service, defined as the charge for transporting one unit (MMBtu) of gas, for two types of customers:

- High-load-factor customers tend to transport gas at a constant level throughout the year. These customers impose a daily demand on the system that is about equal to the average of their annual volume transported. For example, a high-load-factor customer who transports 365

[67]The pipeline routes and companies in the sample were chosen for the analysis because they have a diverse load profile, have a geographically dispersed service area, and have readily available tariff schedules. The pipeline routes account for 43 percent of total U.S throughput. See Appendix E for additional information including the names of pipeline companies included in this analysis.

Figure 13. Interstate Transportation Corridors Used in Corridor Rate Analysis



Source: Energy Information Administration (EIA), EIAGIS-NG Geographic Information System.

MMBtu of gas per year will tend to transport about 1 MMBtu of gas per day. The industrial customers, such as an aluminum plant or food processing plant, with a high load factor tend to have gas requirements that are related to manufacturing needs as opposed to the seasonal demand for space heating. Some electric generators may have uniform usage throughout the year and thus be characterized as high-load-factor customers.

- Low-load-factor customers do not take gas at a constant rate throughout the year. These customers have a peak daily usage that far exceeds the average of their annual use. Residential and commercial sectors are generally low-load-factor customers because they depend on natural gas as a space-heating fuel. Their demand tends to fluctuate with weather temperature. Hence, the pipeline company must be prepared to meet the load requirement of these customers up to the maximum amount of capacity reserved even though the maximum load may occur only a few times a year.

The comparison of load factor rates illustrates the effect of the switch from the modified fixed-variable (MFV) rate design to the straight fixed-variable (SFV) rate design. As discussed earlier in this chapter, many elements affect rates for pipeline service. Except for the change in rate design to SFV, each element will have the same general effect on customers regardless of their load factor. However, the switch from MFV to SFV rate design will tend to have a different impact on maximum tariff rates depending on the load factor, increasing low-load-factor rates while decreasing high-load- factor rates. (For additional information see Chapter 2.)

For this analysis a 100-percent load factor was used to represent high-load-factor customers and a 40-percent load factor for low-load-factor customers. The 40-percent load factor assumes that the low-load customers will impose a peak-day load on the system that is two and one half times the customers' average daily requirements. The load factors were selected for purely illustrative purposes. Actual load factors for shippers may vary from these assumed levels, depending on their service requirements throughout the year. For local distribution companies, this will depend on the mix of residential, commercial, industrial, and electric utility customers and their service requirements.

The average unit rate paid by 100-percent and 40-percent load-factor customers will vary depending on the level of the pipeline company's reservation charge. For example, assume that firm transportation rates include a $0.25 per MMBtu daily reservation charge and a $0.05 per MMBtu usage charge. The 100-percent load-factor customer that transports 1 MMBtu per day will pay, on average, $0.30 per MMBtu for service (1 MMBtu reservation at $0.25 per MMBtu + 1 MMBtu usage at $0.05 per MMBtu). The 40-percent load-factor customer, however, will need to reserve enough space to meet his peak requirements. If the 40-percent load-factor customer transports an average of 1 MMBtu per day, its peak requirements would equal 2.5 MMBtu (load factor = average use/peak use = 40 percent = 40/100 = 1/2.5). Therefore, the 40-percent load-factor customer will pay an average rate of $0.675 per MMBtu for service (2.5 MMBtu reservation at $0.25 per MMBtu + 1 MMBtu usage at $0.05 per MMBtu). (This simplified example ignores the seasonal rates pipeline companies may offer.)

Findings of the Corridor Rate Study

No clear pattern emerges with respect to the change in maximum tariff rates and the respective corridor, supply area, or delivery point. However, there are some noteworthy differences between the 100-percent and the 40-percent load-factor rates. As discussed earlier, the change in rate design was the one phenomenon expected to have different impacts on high- and low-load-factor customers. If the switch in rate design to SFV were the only change during the period, all high-load-factor rates would be expected to decrease and all low-load-factor rates to increase.

It appears that the conversion to SFV rate design was the dominant influence on rate changes for both high- and low-load-factor customers from 1991 through 1994. While other influences may have mitigated SFV's downward pressure on high-load-factor rates and upward pressure on low-load-factor rates, the rate design shift widened the gap between high- and low-load-factor rates. Half the sampled 100-percent load-factor corridor rates increased between 1991 and 1994, while half decreased (Table 9). For the 40-percent load-factor rates, one-third of the corridor rates decreased while two-thirds increased. This higher incidence of rate increases for the low-load customers suggests that recent regulatory changes have benefited low-load-factor customers less than high-load-factor customers. Although both categories of customers had increases and decreases in tariffs, the change was more advantageous to the high-load-factor customers. More compelling evidence is provided by inspecting the differentials in the magnitudes of the rate changes. For instance, in every case where the high-load-factor rate increased, the low-load-factor rate also increased. Moreover, in all cases, the increase was larger in both absolute and percentage terms for the low-load-factor customers. For example, the high-load-factor rate for Canada to New York increased by 4 percent while the low-load-factor rate increased by 19 percent.

In about half of the cases considered, rates to the high-load-factor customers declined, while rates to the low-load-factor customers either decreased by a smaller amount or actually increased. For example, on route A from the Gulf Coast to Boston, the 100-percent load-factor rate declined by 23 percent while the 40-percent rate declined by 8 percent. On the Gulf Coast to Louisville route, the 100-percent rate declined 18 percent. In sharp contrast, the 40-percent rate on the same route increased by 9 percent.

The results of the analysis suggest that the hypothesis that all high-load-factor customers would face decreases in transmission rates and all low-load-factor customers would suffer economically as a result of Order 636 is overly simplistic. For both sets of customers, some rates increased between 1991 and 1994 while others declined. Clearly, there are elements other than the switch to SFV that had an impact on rates during this period. What is striking, however, is the large difference between the two customer classes in terms of the magnitudes of the rate changes. On any given route, the high-load-factor customers experienced a rate change that was more advantageous than the rate change experienced by the low-load-factor customers. This has resulted in a widening of the gap between the 100-percent and the 40-percent load-factor rates between 1991 and 1994. Thus, SFV had a dominant influence on the widening gap in rates for these customer classes. As striking as these results are, they may actually understate the actual impact, because the data used in this analysis are for maximum posted rates. In reality, rates may be discounted. Discounted rates will tend to be obtained by high-load-factor customers, such as industrial customers with alternative fuel capability. Accordingly, the actual differentials in the percentage increases and decreases between the two customer classes are probably larger than those presented in this report.

In addition to the cost-of-service issues discussed earlier in this chapter, a number of regulatory elements affect rates. While rate design may have the most significant direct impact on rates, transition costs resulting from recent regulatory changes also affect rates. Order 636 transition costs include: (1) unrecovered gas costs, (2) gas supply realignment (GSR) costs, (3) stranded costs, and (4) the cost of new facilities.[68] Of these transition costs, the GSR and stranded costs are passed through to customers in the adjustment charges included in the corridor rates. These charges increase overall

[68]Federal Energy Regulatory Commission Docket No. RM91-11-002, et al., Order 636-A, August 3, 1992, p. 336.

Table 9. Estimated Maximum Rates for Firm Transportation Service on Selected Interstate Pipeline Routes, 1991 and 1994
(1994 Dollars per Million Btu)

Supply to Market Routes	100-Percent Load Factor			40-Percent Load Factor		
	1991	1994	Percent Change	1991	1994	Percent Change
Northeast Region						
Gulf Coast to Boston						
Route A	1.28	0.98	-23	2.19	2.01	-8
Route B	0.55	1.11	102	0.93	2.42	160
Appalachia to Boston						
Route A	0.88	0.74	-16	1.55	1.54	-1
Route B	0.44	0.52	18	0.73	1.14	56
Canada to Boston						
Route A	0.85	0.98	15	1.69	2.26	34
Route B	0.52	0.64	23	0.71	1.43	101
Gulf Coast to New York						
Route A	0.55	0.97	76	0.93	2.09	125
Route B	0.93	0.75	-19	1.58	1.49	-6
Route C	0.85	0.56	-34	1.48	1.03	-30
Canada to New York	0.80	0.83	4	1.69	2.01	19
Southeast Region						
Gulf Coast to Louisville	0.66	0.54	-18	1.08	1.18	9
Gulf Coast to Miami	0.38	0.55	45	0.73	1.19	63
Arkoma to Louisville	0.75	0.77	3	1.15	1.68	46
Midwest Region						
Gulf Coast to Detroit						
Route A	1.03	0.82	-20	1.82	1.80	-1
Route B	0.71	0.54	-24	1.13	1.14	1
Route C	0.43	0.55	28	0.78	1.24	59
Central Region						
Rocky Mountain to Denver	0.38	0.39	3	0.67	0.83	24
Mid-Continent to Kansas City	0.44	0.47	7	0.70	1.03	47
West Region						
San Juan to Southern California	1.04	0.80	-23	1.35	1.26	-7
Canada to Southern California	1.53	1.36	-11	1.53	2.52	65
Southwest Region						
Arkoma Basin to Little Rock	0.46	0.29	-37	0.70	0.59	-16

Sources: Energy Information Administration, Office of Oil and Gas, derived from: 1991: Gulf Coast to Miami—H. Zinder & Associates, Summary of Rate Schedules of Natural Gas Pipeline Companies (March 1991); Other corridors—Foster Associates, Competitive Profile of U.S. Interstate Pipeline Companies (October 1991); 1994: Federal Energy Regulatory Commission (FERC) Automated System for Tariff Retrieval (FASTR); and Foster Associates, Competitive Profile of Natural Gas Services (December 1994).

transportation costs for firm service customers. The cost of new facilities associated with Order 636 would tend to increase tariff rates.

Rate increases on a particular pipeline may be caused by the loss of customers who either chose to exercise their alternative fuel capabilities or chose other transportation options. (As discussed earlier, Orders 436 and 636 opened opportunities for customers to switch service providers.) As customers leave a pipeline system, its fixed costs may be recovered by fewer customers and lower throughput volumes, leading to increased rates. Pipeline companies may also be discounting services to retain certain customers and passing on additional costs to other customers who have no other service options (captive customers). Order 636 permits pipeline companies to discount services on a nondiscriminatory basis to meet competition. In order not to discourage discounting, FERC allows the discounted "units" to be factored into the determination of maximum rates. [69]

In a competitive market, price differences across firms reflect quality and geographic (e.g., locational) differences. Price differences in excess of what can be accounted for by these elements may indicate the market's inefficiency at setting prices. On this score, the convergence in corridor rates, while not conclusive, suggests that the market for transportation became more efficient during the period 1991 through 1994.

Comparing pre- and post-Order 636 rates in the corridors served by multiple pipelines suggests that transportation services offered by different pipeline companies may have become more similar, as evidenced by a convergence in rates. In the sample, multiple routes are available within five corridors: Gulf Coast to Boston, Appalachia to Boston, Canada to Boston, Gulf Coast to New York, and Gulf Coast to Detroit (Table 10). For 100-percent load-factor rates, three out of five of these corridors showed a trend toward a convergence of rates, one corridor showed no change, and the fifth showed a modest increase in the variation of rates (Figure 14). The corridors that did exhibit convergence displayed a substantial reduction in the variation in rates. For example, for the two routes from the Gulf Coast to Boston, the rate difference for high-load-factor customers declined from $0.73 per MMBtu in 1991 to $0.13 per MMBtu in 1994 (Table 10). Particularly notable in this analysis is that low-load-factor customers have also seen a reduction in the rate variation in four out of five corridors. However, this reduced variability results from low-end rates moving up to the level of high-end rates rather than a reduction in high-end rates.

[69]In other words, a pipeline company that transports 100 MMBtu of gas at half of its maximum transportation rate will develop rates assuming 50 MMBtu were transported for that service. If the transportation costs remain the same, firm transportation rates will increase because those costs will be recovered on fewer units of gas.

The reduced variability in rates may indicate that in addition to, or possibly as a result of competition, firm transportation services provided by various pipeline companies have become more similar. That is, notwithstanding geographical considerations, a customer may be able to substitute the transportation service offered by one company for transportation service offered by another. In addition, Order 636's directive to use a common rate design method for all pipeline companies may have led to more similarity in the rates offered by pipeline companies serving the same corridor. While intriguing, the finding of rate convergence should be interpreted with a high degree of caution given the small number of corridors on which the finding is based.

As previously discussed, the study cannot isolate numerous influences on the outcome of maximum firm transportation rates. Also, affecting the net cost of transportation is the revenue received for capacity release. Capacity release revenue credits are passed through to firm transportation customers; however, the unit decrease is not reflected in the maximum transportation rate. The extent of the released capacity's influence on transportation rates will depend on the development of the secondary market.

Capacity Releases and Transportation Rates

The capacity release program is another provision of Order 636 that has the potential to affect transportation rates directly. Prior to Order 636, capacity rights on a pipeline were nontransferable. A customer could either use the capacity itself or it would be available to the pipeline company with no compensation to the customer. Under Order 636, a shipper with excess reserved capacity can release that capacity to another shipper in return for a credit on its reservation charges.[70]

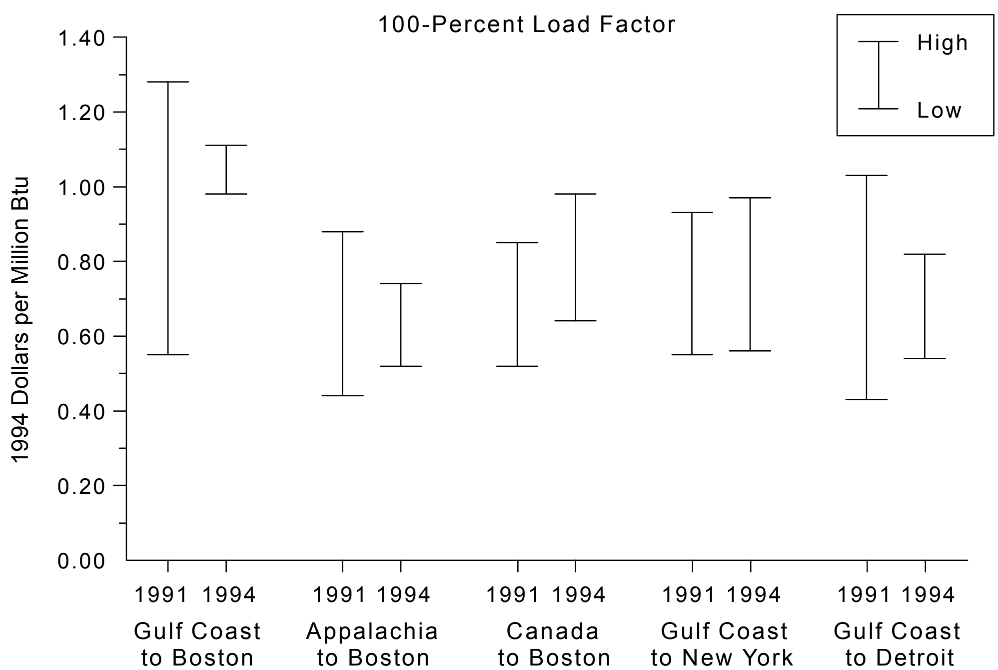
[70]There are two ways in which a release arrangement is processed. (1) A releasing shipper may make a prearranged deal with the replacement shipper if the price for the capacity is equal to the maximum firm rate in the tariff or if the duration of the contract does not exceed one calendar month. (2) If neither of these conditions are met, the releasing shipper will post the release (along with the corresponding limitations or conditions, such as recall rights and award criteria) on the pipeline company's electronic bulletin board where prospective replacement shippers bid on the capacity rights. This process results in capacity release rates that are set by the market conditions instead of a FERC ratemaking process. Currently, the maximum rate for capacity release may not exceed the maximum firm rate stated in the pipeline company's tariff.

Table 10. Range of Maximum Transportation Rates for Corridors with Multiple Routes, 1991 and 1994 (1994 Dollars per Million Btu)

Supply to Market Corridors	100-Percent Load Factor		40-Percent Load Factor	
	1991	1994	1991	1994
Gulf Coast to Boston	0.73	0.13	1.26	0.41
Appalachia to Boston	0.44	0.22	0.82	0.40
Canada to Boston	0.33	0.34	0.98	0.83
Gulf Coast to New York	0.38	0.41	0.65	1.06
Gulf Coast to Detroit	0.60	0.28	1.04	0.66

Source: Energy Information Administration, Office of Oil and Gas, derived from: 1991: Foster Associates, Competitive Profile of U.S. Interstate Pipeline Companies (October 1991); 1994: Federal Energy Regulatory Commission (FERC) Automated System for Tariff Retrieval (FASTR); and Foster Associates, Competitive Profile of Natural Gas Services (December 1994).

Figure 14. Range of Maximum Transportation Rates for Corridors with Multiple Routes, 1991 and 1994



Source: Energy Information Administration, Office of Oil and Gas, derived from: 1991: Foster Associates, Competitive Profile of U.S. Interstate Pipeline Companies (October 1991); 1994: Federal Energy Regulatory Commission (FERC) Automated System for Tariff Retrieval (FASTR); and Foster Associates, Competitive Profile of Natural Gas Services (December 1994).

Under the capacity release program, a local distribution company (LDC) may assign to others some of its rights to capacity on the pipeline system. This would typically occur during the summer when there is no demand for space heating. If this reassignment of capacity results in new incremental load, the pipeline system will operate on a more uniform basis throughout the year, resulting in more efficient use of the existing pipeline capacity. Capacity release also permits more buyers to reach more sellers by making firm transportation available to shippers who may not otherwise be able to obtain service. For example, prior to capacity release, a shipper would not be able to contract for firm transportation service on a pipeline that was fully subscribed (all capacity was contracted for). However, under capacity release the shipper may be able to use released capacity to connect to the gas supply of its choice.

The revenue generated by capacity release decreases the total cost of pipeline transportation to low-load-factor customers.[71] As discussed earlier, these customers pay reservation charges to hold space on the pipeline to meet their maximum requirement on any single day. These customers frequently underutilize this capacity, which causes their average cost of transportation to be relatively high. The revenue these customers receive for their released capacity offsets some of their transportation costs.

The capacity release market has grown steadily since its full activation on November 1, 1993. Pipeline capacity traded during the 1993-94 heating season (November 1993 through March 1994) amounted to 762 billion cubic feet. Capacity held by replacement shippers during the 1994-95 heating season was 1,570 billion cubic feet. Approximately $568 million in revenue credits from November 1993 through March 1995 were generated by the capacity release market—$528 million from released pipeline capacity and $40 million from released storage capacity. Revenues from pipeline capacity released during the 1994-95 heating season increased in all regions compared with the 1993-94 heating season (Figure 15). For the Northeast Region, the revenues in the 1994-95 heating season totaled almost $74 million, more than double the revenues generated during the 1993-94 heating season. Although the apparent growth in the capacity release market appears promising, its effectiveness at reducing the cost of firm transportation will depend on the unit price received for released capacity compared with that paid for firm transportation.

Rates for released capacity vary from region to region and tend to be significantly less than maximum firm transportation rates. Rates for capacity release transportation represent an average 64 percent discount from the maximum firm transportation rate.[72] The average price for released capacity has been fairly stable except for modest seasonal fluctuations during the winter months (Figure 16). This contrasts with the amount of capacity traded, which has increased steadily (Figure 17). The highly discounted price level may indicate that an abundance of capacity is available from releasing shippers.

The price for capacity release has a pronounced seasonal pattern in the Northeast Region (Figure 18), indicating a strong demand for capacity during winter periods. The prices for capacity release are at their highest levels during the winter season when capacity on pipeline systems is more likely to be constrained. LDC's, who comprise the bulk of the releasing shippers, must retain their capacity to supply gas to their residential and commercial heating-load customers. During the summer months, when pipeline capacity may be underutilized, released capacity is abundant and returns a much lower price. Alternatively, a consistent high average price for released capacity may suggest a consistent strong demand for the capacity. This may be the case in the Southeast Region where the 1994 average price for released capacity was more than three times the national average price (Table 11). The Southeast Region has an expanding gas market and only a few pipelines serving the area. Therefore, capacity may be constrained or there may be only limited released capacity in that region leading to the high prices for released capacity.

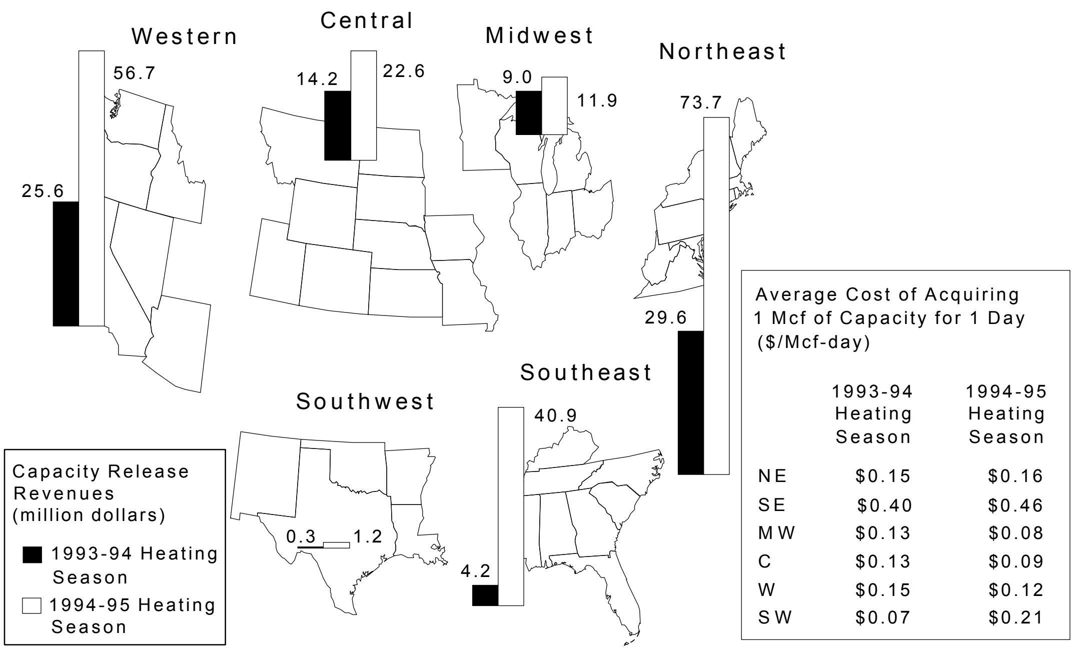
The capacity release market not only reduces the cost of reserving capacity on the system, it also gives replacement shippers a generally low cost alternative to capacity obtained directly from the pipeline company. Before this market emerged, economies of scale limited competition on a corridor to a small number of pipelines. As a result of the emergence of the secondary market, a shipper now can potentially obtain capacity from an average of almost 70 holders of capacity rights on a given pipeline.[73] The number of effective suppliers is probably substantially lower than 70 per pipeline. For example, the shippers may need some of the capacity for themselves; the delivery points of the potential releasing and acquiring shippers may not match; and the excess capacity may be upstream while the capacity desired

[71]Some LDC's with very low load factors may not be able to obtain the revenue crediting benefits from released capacity. The lowest load-factor customers are generally the smallest LDC's. Since they are often served under one-part rates, they are not able to mitigate their costs through capacity release, because it only applies to customers receiving service under two-part rates.

[72]Interstate Natural Gas Association of America, Gas Transportation Through 1994, August, 1995.

[73]See Arthur De Vany and W. David Walls, "Natural Gas Industry Transformation, Competitive Institutions and the Role of Regulation," Energy Policy 1994, 22 (9) 755-763, footnote 31.

Figure 15. Heating Season Revenues from Release of Pipeline Capacity



	1993-94 Heating Season	1994-95 Heating Season
NE	$0.15	$0.16
SE	$0.40	$0.46
MW	$0.13	$0.08
C	$0.13	$0.09
W	$0.15	$0.12
SW	$0.07	$0.21

$/Mcf = Dollars per thousand cubic feet.

Notes: Revenues used in price calculation exclude data with capacity release rates that are stated as a percent of effective maximum rates, capacity transactions with incomplete data, and one transaction with inconsistent release rates. The excluded data account for about 10 percent of pipelin e capacity volumes traded. Also, revenues calculated for capacity transactions with volumetric rates assume 100-percent load factor use of capacity.

Source: Energy Information Administration, Office of Oil and Gas, derived from: capacity release transaction data provided by Pasha Publications, Inc.

may be downstream. Nevertheless, the creation of a secondary market in pipeline capacity represents a substantial increase in the degree of effective competition in the market for pipeline capacity. This creation of an intra-pipeline market in capacity preserves the scale economies inherent in transmission while effectively providing for a competitive and thus more efficient market in pipeline capacity.

Currently several transportation services compete with the capacity release market. These services include traditional interruptible transportation, short-term firm transportation offered by pipeline companies, and capacity obtained through gray market transactions.[74] However, there is little doubt that the emerging capacity release market represents an important institutional innovation.

[74]Short-term firm capacity is that portion of unused firm transportation capacity on its system that a pipeline company decides to sell. The gray market is broadly viewed as transportation or storage that is bundled with gas and sold as a deregulated service by marketers and LDC shippers.

Natural Gas Prices and Markups, 1988-1994

While some transmission rates have declined as a result of changes in Federal policies, others have increased. A cursory analysis might conclude that recent policies have had a mixed effect on the cost of natural gas transmission. However, transmission rates, whether they represent maximum posted or actual transactions, do not fully reflect the impact of policy changes on the cost of moving gas from the wellhead to the citygate or to the burnertip. Recent policy has been to provide both producers and consumers of gas with more choices. Prior to the recent institutional changes, the combined merchant/ shipper status of the pipeline companies resulted in consumers of gas having very limited choices with respect to both gas supply and transmission. The choices currently available to market participants have affected the cost of moving gas in ways that are simply not captured in the tariff rate associated with moving gas from point A to point B. Under the new policies, gas that previously moved from A to B may instead flow at lower overall cost from a new point, C to B.

Table 11. Average Price for Released Pipeline Capacity by Region, 1994 (Dollars per Thousand Cubic Feet per Day)

Region	Price
Northeast	0.11
Southeast	0.45
Midwest	0.09
Central	0.14
Western	0.11
Southwest	0.12
U.S. Average	0.13

Notes: Revenues used in price calculation exclude data with capacity release rates that are stated as a percent of effective maximum rates, capacity transactions with incomplete data, and one transaction with inconsistent release rates. The excluded data account for about 10 percent of pipeline capacity volumes traded. Also, revenues calculated for capacity transactions with volumetric rates assume 100-percent load factor use of capacity.

Source: Energy Information Administration, Office of Oil and Gas, derived from: capacity release transaction data provided by Pasha Publications, Inc.

End-use, citygate, and wellhead prices can be used to estimate transmission and distribution markups to the various end-use sectors. The transmission markup represents the cost of moving gas from the wellhead to the citygate and is calculated as the difference between the citygate price and the wellhead price. The distribution markup represents the LDC's charge for delivering the gas from the citygate to the end user and is calculated as the difference between the retail price to onsystem end users and the citygate price.

The end-use price is the average retail price paid for gas by a single customer class or sector (e.g., residential, commercial, industrial, and electric utility). It includes the costs of the many transactions necessary to bring natural gas from the producing field to the burnertip, including the citygate price and the wellhead price. Between 1988 and 1994, end-use prices for all sectors fell, with the greatest declines experienced by the onsystem industrial and electric utility sectors, 15 and 19 percent respectively. The decline in end-use prices experienced by residential and commercial customers was considerably less, only 4 and 3 percent, respectively (Table 12).

Retail gas price data for the electric utility sector are the only data that encompass both onsystem and offsystem purchases of gas by end users.[75] They show clearly the benefits of enhanced competition and open access in the transportation markets. Not only can electric utility (and industrial) consumers obtain transportation service at lower prices, they can also shop for the lowest priced gas supplies. As a result, real electric utility gas prices declined between 1988 and 1994, but experienced an upturn in both 1992 and 1993 reflecting the increase in wellhead prices in those years.

The citygate price is the average delivered price of gas to the LDC. It represents a weighted average of the delivered cost of gas across all customer classes served by LDC sales. Between 1988 and 1994, the real citygate price declined 13 percent, from \$3.54 to \$3.08 per thousand cubic feet (Table 12). The magnitude of the decline varies by region, with the price falling less than the average in the Northeast (9 percent) and more in the Midwest and West (19 and 18 percent, respectively).

The wellhead price is the price paid to the producer for the natural gas, in other words, the commodity cost. Between 1988 and 1994, the real natural gas wellhead price declined 11 percent, from \$2.05 to \$1.83 per thousand cubic feet (Figure 19 and Table 12).

Because of the different service requirements of the end-use sectors, the relative importance of each component of price varies substantially among the sectors (Figure 20).

- For residential and commercial customers, most of the end-use price is directly related to the costs of local distribution. For instance, the LDC markup accounted for 52 and 43 percent of the total price paid by the residential and commercial consumers, respectively. The costs of transportation services by pipeline companies accounted for 20 and 23 percent of the respective end-use prices, while the wellhead price accounted for 29 and 34 percent, respectively.[76]

[75]Price data for electric utilities are based on reports by the utilities themselves on their total gas purchases. Retail price data for the other sectors are based on reports by pipeline companies and LDC's on their gas sales to these sectors and therefore do not include offsystem sales.

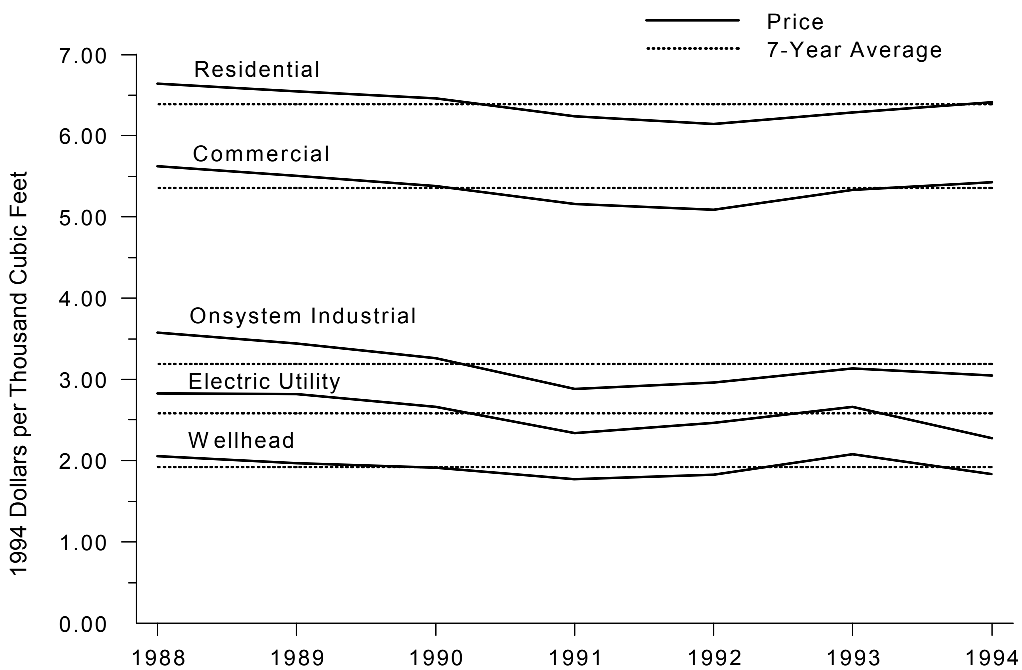
[76]The citygate price used in the calculation of these components is a weighted average of the delivered cost of gas across the customer classes served by LDC sales. Because it may include lower cost onsystem industrial and electric utility volumes, it may understate the delivered citygate price to the residential and commercial sectors. As a result, the distribution markup to residential and commercial customers may be overstated, and the transmission markup may be understated. However, this problem is relatively minor given that approximately 87 percent of deliveries to the citygate in 1994 were accounted for by deliveries to residential and commercial customers.

Table 12. Average Natural Gas Prices and Price Changes, 1988 and 1994
(1994 Dollars per Thousand Cubic Feet)

Price	1988	1994	Price Change	Percent Change
Wellhead	2.05	1.83	-0.22	-11
Citygate	3.54	3.08	-0.46	-13
End Use				
Residential	6.64	6.41	-0.23	-3
Commercial	5.62	5.43	-0.19	-3
Onsystem Industrial	3.58	3.05	-0.53	-15
Electric Utility	2.83	2.28	-0.55	-19

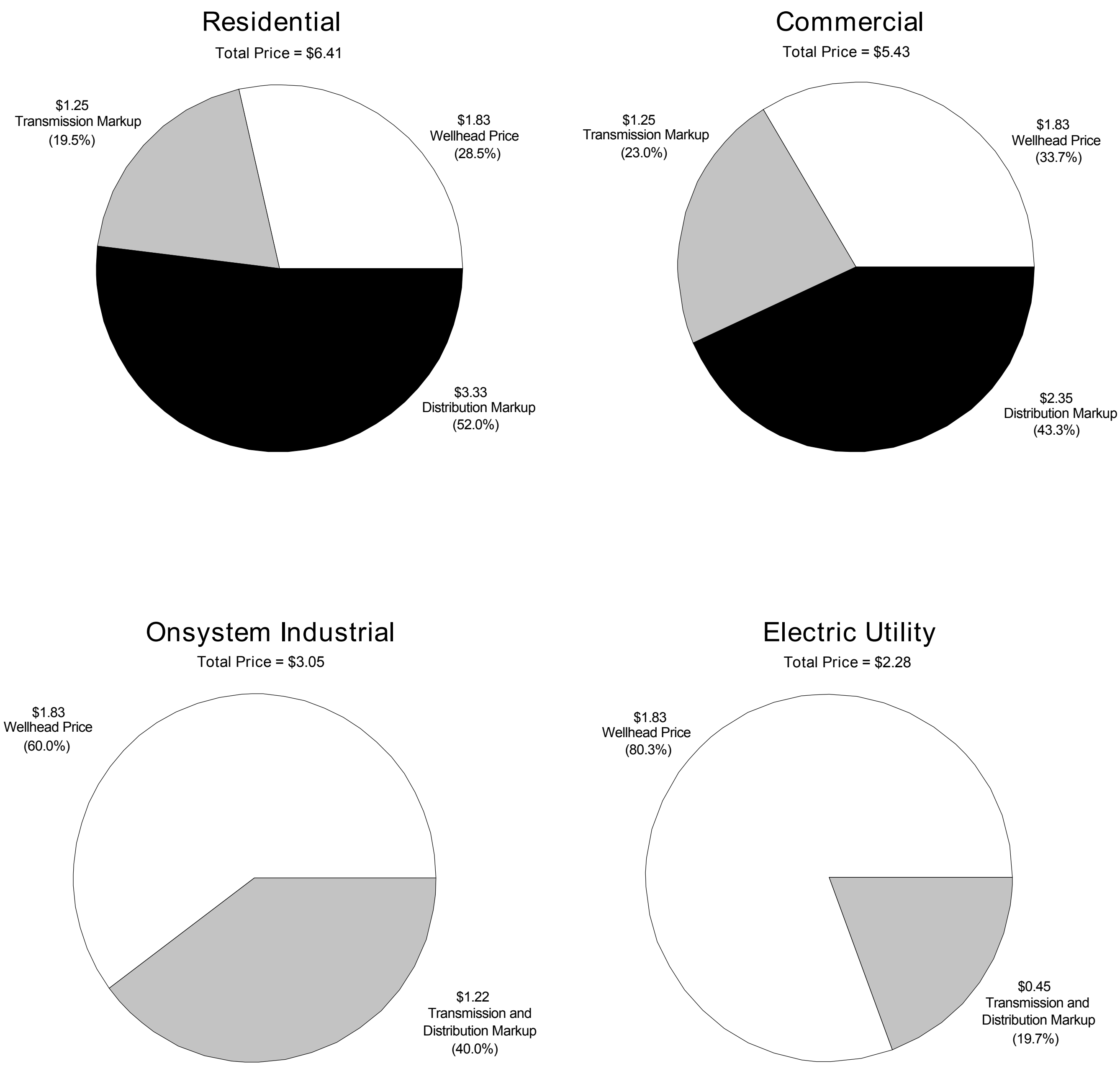
Note: Industrial end-use price data represent onsystem sales only. The onsystem share of total sales to industrial consumers declined from 43 percent in 1988 to 22 percent in 1994.
Sources: Energy Information Administration. 1988: Natural Gas Annual 1992, Vol. 2 (November 1993). 1994: Natural Gas Monthly (August 1995).

Figure 19. Wellhead and End-Use Prices by Sector, 1988-1994



Note: Industrial end-use price data represent onsystem sales only. The onsystem share of industrial deliveries declined from 43 percent in 1988 to 22 percent in 1994.
Sources: Energy Information Administration. 1988: Natural Gas Annual 1992, Vol. 2 (November 1993). 1989-1994: Natural Gas Monthly (August 1995).

Figure 20. Components of End-Use Prices by Sector, 1994
(Dollars per Thousand Cubic Feet)



Note: Industrial end-use price data represent onsystem sales only. In 1994, 22 percent of sales to industrial consumers were onsystem.
Source: Energy Information Administration, Office of Oil and Gas, derived from: Natural Gas Monthly (August 1995).

- For the onsystem industrial and electric utility sectors, the wellhead price of natural gas is the largest component of the total end-use price. In 1994, the wellhead price accounted for 60 percent of the industrial price while the combination transmission and distribution charge accounted for the remaining 40 percent. In the electric utility sector, the wellhead price accounted for 80 percent of the 1994 end-use price while the transmission and distribution charge comprised the remaining 20 percent.

Before proceeding, it should be noted that as a result of data limitations, the end-use prices used to calculate the industrial and commercial transmission and distribution markups reflect only onsystem sales. As a result, the markups overstate the actual markups for these sectors (Figure 21). While this issue is a concern in the case of the commercial sector, where onsystem sales account for 78 percent of deliveries, it is an especially serious limitation in the industrial sector where the burnertip price reflects only 24 percent of the market.

Except for the commercial customers, combined transmission/distribution markups declined during the period 1988 through 1994 (Figure 22). Specifically, the markup for the industrial sector fell by 20 percent, while the electric utility markup declined by 42 percent. The declines in these markups are no doubt largely attributable to the increase in transportation options available to these customer classes during this period.

In fact, average industrial retail prices have been lower than citygate prices as LDC's have attempted to prevent their industrial customers from bypassing their system with direct tie-ins to nearby pipelines. Loss of industrial customers, with their higher and less variable demands, would increase the LDC's unit cost of service. These higher rates would have to be covered by the residential and commercial customers remaining on the system. Therefore it may be to the advantage of all of its customers for LDC's to discount prices to those customers who contribute most to lowering the overall costs of the LDC.

The combined transmission/distribution markup for the residential and commercial sectors declined marginally in the 1988 through 1993 period, but rose modestly from 1993 to 1994. For these sectors, the combined transmission/ distribution markup in 1994 was within 3 cents of the level in 1988. While the total markup paid by these customers has remained roughly constant, the transmission component of the total markup (or the markup to citygate) declined 16 percent in real terms from 1988 to 1994 (Figure 23). This is striking given that some analysts believed that the switch to straight fixed-variable from modified fixed-variable rate design would increase the average cost of transmission for these low-load-factor sectors. As discussed earlier in this chapter, a number of considerations put either upward or downward pressures on maximum tariff rates for pipeline transportation. A possible reason for the lower transmission markup to these sectors is that the higher reservation charges are being spread over a higher volume of deliveries. Also, the regulatory changes during the period may have permitted some LDC's to exploit previously unavailable lower cost transportation options.

In contrast to the transmission markup, the distribution markup for residential and commercial customers was roughly flat in real terms from 1988 through 1993, but increased substantially from 1993 to 1994 (Figure 23). The sharp increase in the distribution markup between 1993 and 1994 may reflect the higher costs incurred by LDC's who, with the unbundling of pipeline company services, have had to take responsibility for security of supply, including storage. Bypass by industrial customers and electric utilities may also have contributed to the increased LDC markups paid by residential and commercial customers in 1994.

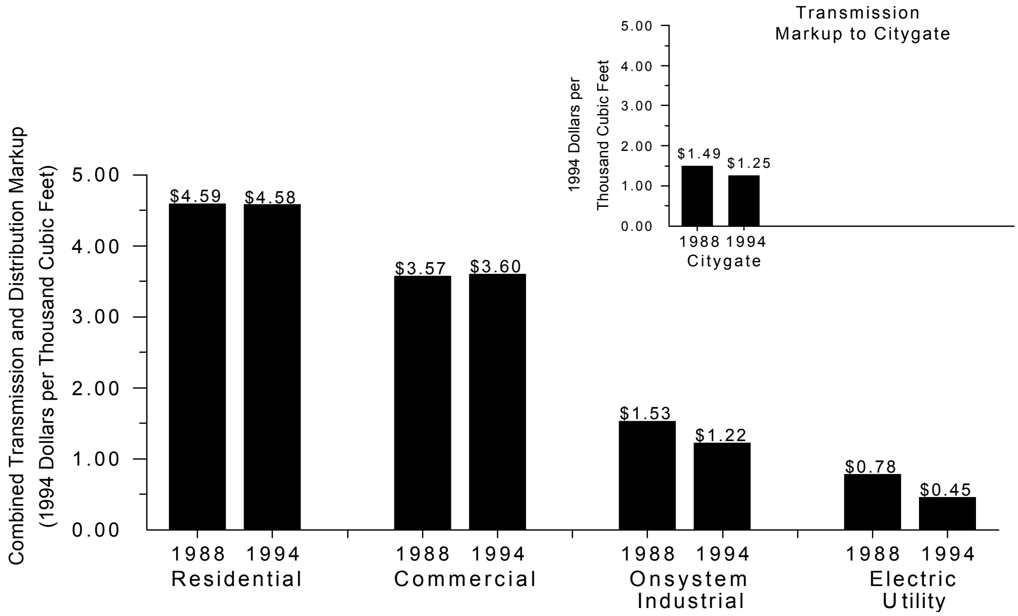
Trends in Regional Prices: End-Use and Citygate

Changes in end-use prices between 1988 and 1994 varied greatly by geographic region (Figure 24). As at the national level, the regional changes were the greatest in the onsystem industrial and electric utility sectors. In most regions, real average prices declined by 10 percent or more in these sectors (1994 dollars).

The largest regional percentage change during the period was a 29-percent drop in the real price of natural gas to electric utilities in the Western Region. In 1988, the price of gas to electric utilities in the Western Region was $3.52 per thousand cubic feet (1994 dollars), the highest of any region. Even after dropping to $2.50 per thousand cubic feet in 1994, electric utilities in this region still paid the highest average price for natural gas of all the regions. The price change from 1993 to 1994 contributed significantly to the overall drop in prices during the period. From 1993 to 1994, electric utility gas consumption increased 30 percent in this region, possibly as a result of drought conditions in the Northwest that reduced the availability of hydroelectric power. The average price of gas to electric utilities fell by $0.57 per thousand cubic feet (1994 dollars) or 19 percent from 1993 to 1994.

The largest actual price change (and second largest percentage change) also occurred in the Western Region, but in the onsystem industrial sector. The real average price of gas to industrial users fell $1.20 per thousand cubic feet

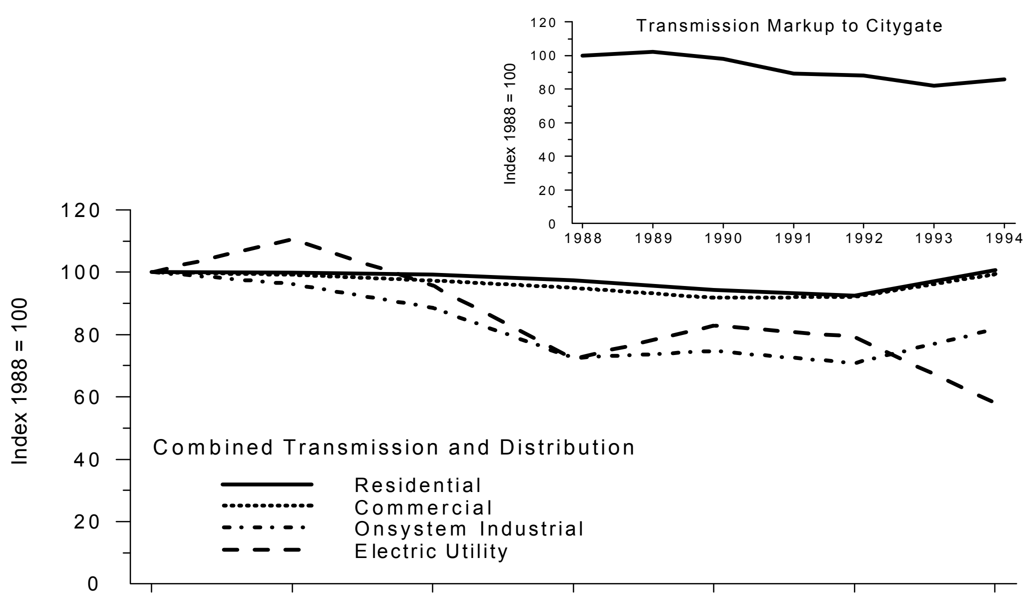
Figure 21. Transmission/Distribution Markups by Sector, 1988 and 1994



Notes: Industrial markups reflect end-use prices for onsystem sales only. The onsystem share of industrial deliveries was 43 percent in 1988 and 22 percent in 1994.

Source: Energy Information Administration, Office of Oil and Gas, derived from: 1988: Natural Gas Annual, Vol. 2 (November 1993); 1994: Natural Gas Monthly (August 1995).

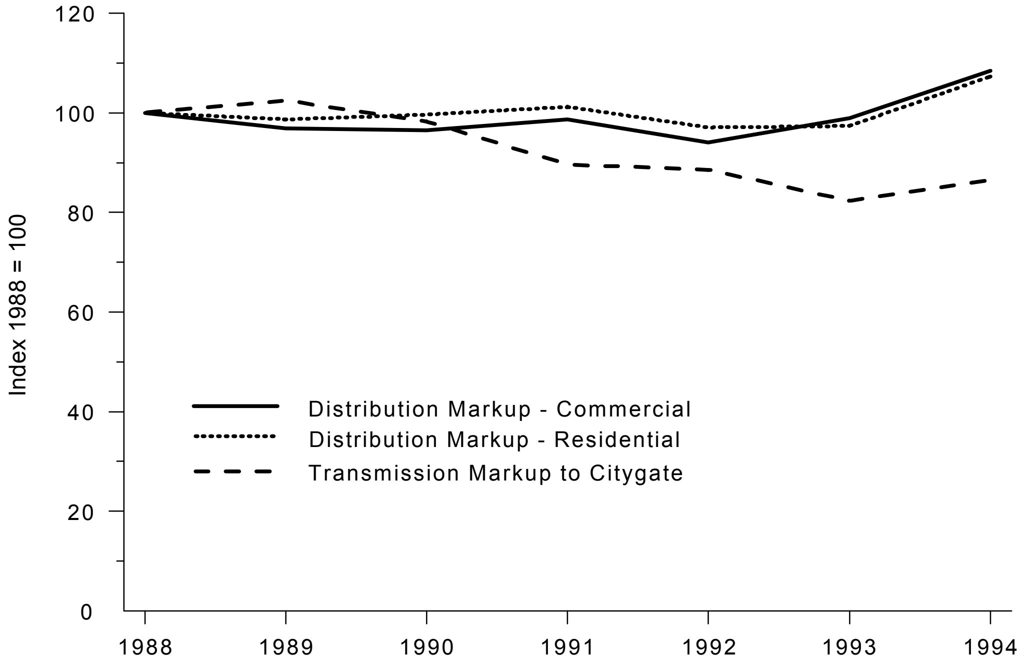
Figure 22. Indices of Transmission/Distribution Markups by Sector, 1988-1994



Notes: Industrial markups reflect end-use prices for onsystem sales only. The onsystem share of industrial deliveries was 43 percent in 1988 and 22 percent in 1994.

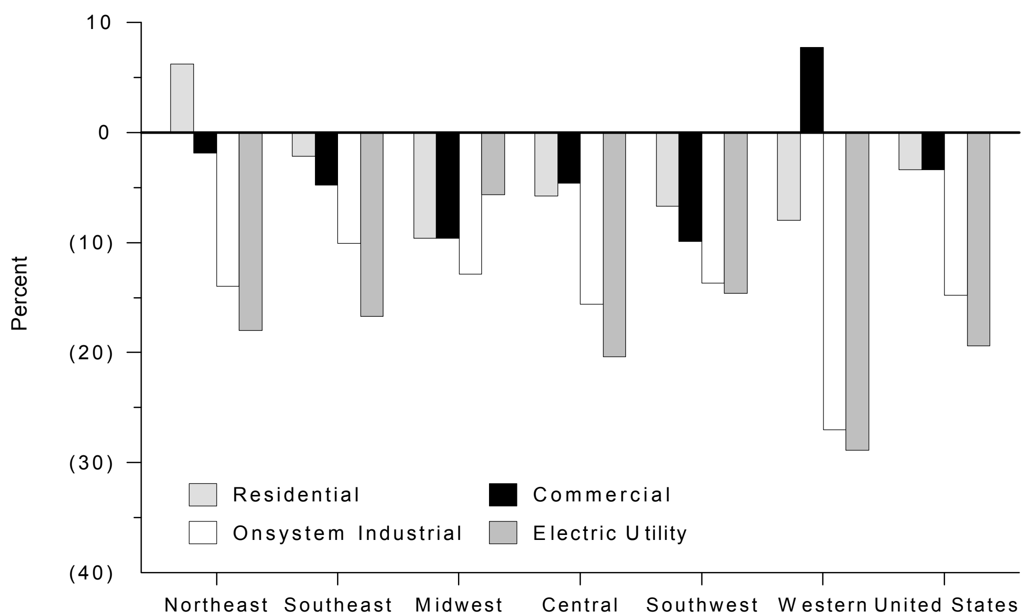
Source: Energy Information Administration, Office of Oil and Gas, derived from: 1988: Natural Gas Annual, Vol. 2 (November 1993); 1989-1994: Natural Gas Monthly (August 1995).

Figure 23. Indices of Residential and Commercial Distribution Markups and Citygate Transmission Markup, 1988-1994



Source: Energy Information Administration, Office of Oil and Gas, derived from: 1988: Natural Gas Annual, Vol. 2 (November 1993); 1989-1994: Natural Gas Monthly (August 1995).

Figure 24. Percentage Change in End-Use Prices by Sector and Region Between 1988 and 1994



Notes: Changes were calculated in 1994 dollars. Industrial end-use price data represent onsystem sales only. The onsystem share of industrial deliveries was 43 percent in 1988 and 22 percent in 1994.
Source: Energy Information Administration, Office of Oil and Gas, derived from: Natural Gas Monthly (August 1995).

(27 percent), perhaps because of competition from Canadian imports. The 1988 price of $4.45 per thousand cubic feet (1994 dollars) was the third highest in the onsystem industrial sector, and by 1994, the Western Region had only the fourth highest industrial gas prices. The average real price to industrial users fell by 10 to 16 percent in all other regions during the period.

The price changes were not as dramatic for residential and commercial users, but average real prices in these sectors did fall from 2 to 10 percent in every region, with two exceptions—residential prices in the Northeast and commercial prices in the Western Region. The price of natural gas to residential users rose $0.47 per thousand cubic feet (6 percent) in real terms in the Northeast Region. Residential gas prices in the Northeast were higher than in any other region throughout the period and reached $8.06 per thousand cubic feet in 1994. The largest decline in real residential prices occurred in the Midwest where real prices fell from $6.15 per thousand cubic feet in 1988 to $5.56 in 1994 (10 percent).

In the commercial sector, the largest real price drop also occurred in the Midwest. Commercial prices fell from $5.51 to $4.98 per thousand cubic feet during the period (10 percent) in this region. While the prices in most other regions fell from 2 to 10 percent, prices rose $0.44 per thousand cubic feet, or 8 percent, to commercial users in the Western Region. This increase moved the Western Region from the third to the second highest priced region for commercial gas users between 1988 and 1994.

Between 1988 and 1994, citygate prices, the average delivered price of gas to the local distribution company, decreased $0.46 per thousand cubic feet, or 13 percent. Although the average citygate price may not broadly apply to any specific customer sector, it may indicate the regional cost to customers. Comparing 1994 and 1988 citygate prices across the regions, the price decrease ranged from $0.26 per thousand cubic feet (8 percent) in the Central Region to $0.72 per thousand cubic feet (19 percent) in the Midwest (Figure 25). For all but two regions (Northeast and Central), the decrease in the citygate price exceeded $0.50 per thousand cubic feet, representing at least a 15-percent reduction since 1988. The smaller reduction in the Northeast probably reflects the costs associated with incremental pipeline capacity added between 1988 and 1994 as well as the great distance between this region and the major supply areas of both the United States and Canada. For each region, the decrease in citygate prices exceeded the average decrease in the wellhead price ($0.22 per thousand cubic feet). This points to an overall reduction in the costs for interstate transmission. The relatively sharper declines in the Southeast ($0.56 per thousand cubic feet), Midwest ($0.72 per thousand cubic feet), and Southwest ($0.62 per thousand cubic feet) may suggest that local distribution companies in these regions derive more direct benefits from reduced transportation costs.

Conclusion

FERC Order 636, issued in 1992 and implemented in November 1993, probably had the most significant direct effect on transportation rates between 1988 and 1994. Specifically, Order 636 separated the pipeline's merchant/ shipper role; unbundled transportation, storage, and ancillary services; changed the method of computing transportation rates; and initiated a capacity release program that allows customers to reassign their capacity rights for a revenue credit. The costs to pipeline companies of complying with Order 636 and restructuring their operations (transition costs) have also affected rates. As of August 1995, $2.7 billion in transition costs, for eventual recovery from pipeline customers, had been filed at FERC.

Prior to FERC Order 636, Order 436 (issued in 1985) initiated industry restructuring by encouraging pipeline companies to offer open access. Open access promoted producer competition, exerting downward pressure on wellhead prices. Other legislation and policies, such as the Clean Air Act Amendments, have indirectly affected transportation rates by expanding gas markets and/or encouraging conservation, Also, rates paid between 1991 and 1994 were strongly influenced by greater efficiency in operations, the cost of capacity additions, and take-or-pay costs incurred by pipeline companies.

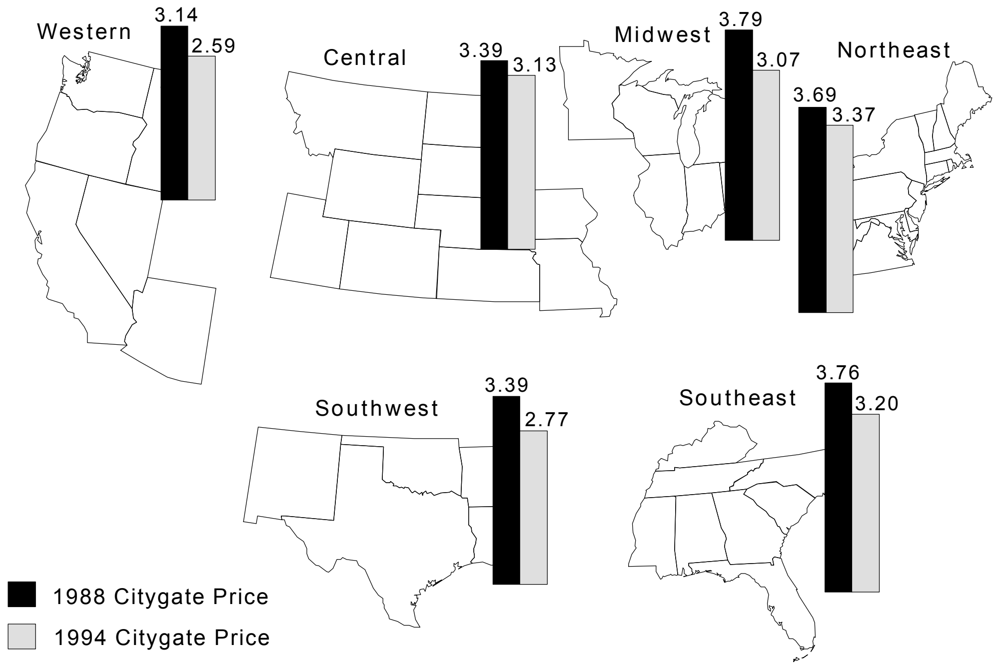
Additional conclusions are:

- On average, customers are paying less (in real terms) for natural gas service in 1994, compared with 1988. This includes declines of 11 and 13 percent in the wellhead and citygate prices, respectively, and an average decline of between of 3 and 19 percent in end-user prices. Residential and commercial prices generally declined the least, while electric utility prices declined the most. Onsystem industrial prices declined almost 15 percent between 1988 and 1994.

- Between 1988 and 1994, total transmission and distribution markups to the residential and commercial sectors remained fairly constant in real terms, while comparable prices to the onsystem industrial and electric utility sectors declined dramatically by 20 and 42 percent, respectively.

- Transmission costs, the cost of moving gas from the wellhead to the local distributor, decreased 16 percent in real terms between 1988 and 1994. However, the

Figure 25. Citygate Prices by Region, 1988 and 1994
(1994 Dollars per Thousand Cubic Feet)



Source: Energy Information Administration (EIA), Office of Oil and Gas, derived from: a special extract from Form EIA-857, "Monthly Report of Natural Gas Purchases and Deliveries to Consumers."

decrease in the transmission component was almost completely offset by an average real price increase of 7 and 13 percent in the local distribution company markup for the residential and commercial sectors, respectively. Although total transmission and distribution markups to captive residential and commercial consumers have remained fairly constant in real terms, they may be benefiting from the increased competition in interstate transportation.

- The analysis of maximum allowable rates suggests that low-load-factor customers have benefited less than high-load-factor customers from the recent regulatory changes. Although both categories saw both increases and decreases in tariffs, in all cases the change was more advantageous to the high-load-factor customers.

- While other influences may have mitigated SFV's downward pressure on high-load-factor rates and upward pressure on low-load-factor rates, the change in rate design was the dominant influence in widening the gap between the rates paid by the two groups. Except for the change in rate design, other key determinants of firm rates would tend to have the same general impact on customers regardless of their load factors.

- Comparing pre- and post-Order 636 rates in the corridors served by multiple pipelines suggests that transportation services offered by different pipeline companies may have been more comparable over the period. The variation among pipelines in a corridor is decreasing—with the decrease being more pronounced for low-load-factor customers. The comparison shows some convergence of rates between 1991 and 1994 for several of the corridors. One possible explanation is that increased competition and integration of the pipeline grid may have increased the comparability of services offered by pipeline companies. In addition, Order 636's directive to use a common rate design method for all pipeline companies may have led to more similarity in the rates offered by pipeline companies serving the same corridor.

- Total revenues generated by the capacity release program from November 1993 through March 1995 totaled $568 million. Trading of capacity has increased significantly since the program began and currently represents 13 percent of the overall volumes moved to market. On average, capacity trades at a 64-percent discount from maximum rates.

- The regional rates for released firm capacity vary significantly. Rates in the Southeast are higher than those in other regions possibly because of capacity constraints or the relative unavailability of released capacity in the region.